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April 9, 2004

VIA E-MAIL AND HAND DELIVERY

Ms. Mary Cottrell
Secretary
Department of Telecommunications and Energy
One South Station, 2nd Floor
Boston, MA 02110

Re: <u>NSTAR Electric, D.T.E. 03-121</u>

Dear Secretary Cottrell:

Enclosed for filing in the above-captioned matter are the following:

1. Responses to Information Request DTE – TEC 1-1 to 1-3; and
2. Responses to Information Request DTE – NEDGC 1-7 to 1-10.

Kindly file and docket same. If you have any questions please contact me.

Sincerely,

Robert M. Granger

RMG:km
Enclosures

cc: William Stevens, Hearing Officer (by hand)
John Cope-Flanagan (by hand)
Sean Hanley (by hand)
Claude Francisco (by hand)
Xuan Yu (by hand)
Robert Harrold (by hand)
David S. Rosenzweig (by hand)
Service List (by mail)

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company	)	
Cambridge Electric Light Company	)	D.T.E. 03-121
Commonwealth Electric Company	)	
d/b/a NSTAR Electric	)	

CERTIFICATE OF SERVICE

I certify that I have this day served the foregoing documents upon the Service List of the above-entitled proceeding in accordance with the requirements of 220 C.M.R. 1.05(1) (Department's Rules of Practice and Procedure.)

Dated at Boston, this 9th day of April, 2004,

Robert M. Granger
FERRITER SCOBBO & RODOPHELE, PC
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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Information Request DTE-TEC 1-1

In reference to the pre-filed testimony of Elaine Saunders at 4, please state the units of the items shown under columns labeled “All G-3" and “Cogens” and provide all the supporting data used as the basis for calculating the indicated figures.

Response

In the table on page 4 in the testimony of Ms. Saunders, the numbers in the “All-G-3” column are the number of customers on Rate G-3 whose ratio of the smallest billing demand to the largest during the test year falls in each category. For instance, 48 customers had a minimum/maximum ratio less than 10 percent, 57 had a ratio between 10 and 20, etc. The numbers in the “Cogens” column show the same information, but only customers with generation are included.

See the response to NSTAR-TEC-1-6 for the supporting data.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Information Request DTE-TEC 1-2

Please develop a schedule for each NSTAR affiliate, similar to the schedule shown on page 4 of the pre-filed testimony of Elaine Saunders, using the NSTAR Electric data to be provided in response to The Energy Consortiums information request as noted on page 5, lines 6-8, of the testimony.

Response

DTE-TEC-1-2

The requested information is provided in the tables below. The customer in the "Camb Gens" column is MIT, which is served on Rates SB-1, SS-1 and MS-1. All other customers are on Rates G-3, T-2 or G-2.

Min/Max up to:	BECO Total	% Total	BECO Gens	% Total
10%	124	6%	1	8%
20%	69	3%	0	0%
30%	117	5%	1	8%
40%	203	9%	2	17%
50%	309	14%	3	25%
60%	359	17%	2	17%
70%	394	18%	2	17%
80%	348	16%	1	8%
90%	187	9%	0	0%
100%	40	2%	0	0%
Total	2150	100%	12	100%

Min/Max up to:	Camb Total	% Total	Camb Gens	% Total
10%	11	3%	0	0%
20%	13	4%	1	100%
30%	17	5%	0	0%
40%	27	8%	0	0%
50%	71	20%	0	0%
60%	68	19%	0	0%
70%	75	21%	0	0%
80%	51	14%	0	0%
90%	15	4%	0	0%
100%	6	2%	0	0%
Total	354	100%	1	100%

Min/Max up to:	Comm Total	% Total	Comm Gens	% Total
10%	14	3%	0	0%
20%	12	3%	1	33%
30%	25	6%	0	0%
40%	30	7%	1	33%
50%	53	13%	0	0%
60%	85	21%	0	0%
70%	104	25%	1	33%
80%	53	13%	0	0%
90%	30	7%	0	0%
100%	3	1%	0	0%
Total	409	100%	3	100%

Min/Max up to:	Nstar Total	% Total	Nstar Gens	% Total
10%	149	5%	1	6%
20%	94	3%	2	13%
30%	159	5%	1	6%
40%	260	9%	3	19%
50%	433	15%	3	19%
60%	512	18%	2	13%
70%	573	20%	3	19%
80%	452	16%	1	6%
90%	232	8%	0	0%
100%	49	2%	0	0%
Total	2913	100%	16	100%

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Information Request DTE-TEC 1-3

In reference to the pre-filed testimony of Elaine Saunders at 10, lines 12-14 please provide any available data showing customers with multiple generating units. Provide historical data on failure rates of each generating unit in each customers portfolio of generating units.

Response

TEC does not have any data showing the outage of multiple generation units, but the likelihood of simultaneous outages is smaller than the outage of each unit. For example, suppose a customer has two 100 kW units (generators A and B), each available 92 percent of the time. Then the combined availability of the two units is:

Configuration:	**Formula:**	**Probability:**
Both On	.92 * .92	0.8464
Gen A On, B Off	.92 * .08	0.0736
Gen A Off, B On	.08 * .92	0.0736
Both Off	.08 * .08	0.0064
Total		1.0000

Notice that the likelihood of both units being down (.0064) is a lot smaller than the rate per unit (.08 each). Similarly, for more units, again assuming .92 availability, the likelihood that all units are down simultaneously is:

# Units:	**Formula:**	**Probability:**
3	.08 * .08 * .08	.0005
4	.08 * .08 * .08 * .08	.0000

This shows that the greater the number of units, the probability that all units will be off simultaneously is increasingly small, so that in practical terms the probability is zero or near zero for three or more units.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Information Request DTE-NEDGC 1-7

Refer to the Direct Testimony of Sean Casten at 6, lines 16-17. Please explain how the benefits of DG should be incorporated into the standby rates proposed by NSTAR Electric. Please be specific regarding the monetary valuation of such benefits.

Response

Generally speaking, the benefits that result from the installation of DG can be described as follows:

1) Deferral of investment in upstream distribution, transmission and generation assets.
2) Reduction of transmission and distribution line losses through reduction in grid congestion.
3) Export of reactive power onto grid (some DG technologies)
4) Reduction in energy prices (fuel and electric) due to gains in generation efficiency (some DG technologies.)
5) Reduction in emissions of air pollutants associated with power generation, including greenhouse gases (some DG technologies).

Of these five, the first three are relatively straightforward to put a financial value on, although one does need to recognize that not all of the financial values created necessarily accrue to the regulated distribution utility. The fourth is harder to put a direct monetary value on, although it can be estimated, and the fifth is nearly impossible to monazite under current environmental regulations. However, all benefits are quite real, and it is critically important for the DTE to appreciate that a failure to place an accurate financial value on each of these benefits will necessarily lead to a misallocation of capital by DG developers.

In the remainder of this answer, I outline a suggested methodology for the calculation of these benefits. Where possible, I have used actual data from NSTAR's grid to calculate, but recognize that I do not have access to all the data required to do a rigorous calculation herein. As such, please treat this answer as an explanation of the methodology one should use to calculate the benefits created by DG rather than a calculation of the precise dollar value that should actually be credited to a DG installation on NSTAR's system.

Deferral of T&D costs

A kilowatt of DG capacity will defer an investment in upstream transmission and distribution costs only to the extent that the kilowatt of generation is operating at full capacity during a period of peak grid load. The probability that a given DG unit will be operational during peak grid demand is a function both of the overall reliability of the unit in question (e.g., what is the chance that it will be down for repair at any given time?) and the coincidence of the DG peak with the grid peak (e.g., of the total rated DG capacity, how much is it likely to be generating during the grid peak if it is not down for repair?) Mathematically, these two probabilities can be conflated to estimate the total kW capacity of upstream infrastructure displaced by a DG installation as:

Rated kW of DG unit x Reliability of DG unit (%) x % of rated power DG unit produces during coincident peak with system component in question.

To be complete in this analysis, one should also factor in the reserve margin built into the grid infrastructure, since every kW of peak load necessarily requires more than 1 kW of peak capacity to serve. Thus, if NSTAR builds a 10% reserve margin into their grid, a 1 kW load must therefore require 1.1 kW of NSTAR distribution capacity to serve, and a 100 kW reduction in that peak load reduces NSTAR's capital requirements not by 100 kW but rather by (1100 MW – 1.1x900 kW) = 110kW.

Thus, a 100 kW, baseloaded DG plant that has a 95% reliability that is installed on a system with a 10% reserve margin would displace:

Eq. 1 1.1 x 100 kW x 0.95 x 1.0 = 104.5 kW of upstream T&D capacity.

(A baseloaded system is by definition generating 100% of its peak capacity at all times that it is operational, thus allowing for the 1.0 factor in the final term. A system with a peakier load would have a factor of less than 1.0 for this term to the extent that its peak operation did not coincide with the system peak, and would in all likelihood have a different coincident peak with different upstream assets. This would make the precise determination of this variable more complex, but the underlying mathematics remains the same.)

Once this calculation of deferred T&D costs is made on a kW basis, converting it into a financial benefit is simply a matter of knowing what the cost of the upstream grid is, per kW of *delivered* capacity at the end of the wire. According to an analysis done by consulting firm Arthur D. Little, the average U.S. transmission and distribution system infrastructure costs per kW of delivered load are as follows:[1]

Grid component	U.S. Average Cost, $/kW
Transmission	$540
Substation	$39 – 211
Distribution	$720
Total	**$1,299 - $1,471**

Thus, on a national average basis, the deferred capital costs throughout the entire grid infrastructure for the 100 kW example shown above would be approximately $135,850 ($1,300/kW x 104.5 kW of displaced system capacity).[2] Ideally, one would like to have more precise numbers for a given region, since these costs can vary substantially nationwide, and one would also like to have marginal (rather than average) costs to better reflect the actual dollar displacement by a reduction in a single kW of peak load. Fortunately, we have this data for NSTAR's service territory from their 1992 Marginal Cost of Service Study (DPU 92-92), which formed the basis for the current NSTAR rate schedules. See NSTAR's response to DTE 2-23. According to this study, the actual costs for a marginal kW of system capacity in NSTAR's service territory are as follows:[3,4]

1 Source: Casten, Sean and Robert Zogg. "Preliminary Assessment of Battery Energy Storage and Fuel Cell Systems in Building Applications", Final report to national Energy Technology Laboratory, U.S. Department of Energy Contract No. GS-23F-8003H, Order No. DE-AD26-99FT01038, Item No. 1. Arthur D. Little, Inc., Cambridge, MA. August 2, 2000.
2 It is sometimes argued that this value is not displaced, but rather is stranded since the utility can no longer earn revenue from this distribution asset which was made prior to the investment in DG. However, this assertion is only true if system load is not growing, since steadily rising demand both at the DG users' facility and elsewhere on the grid necessarily imply that these assets are simply temporarily-idled, and the long-term impact of DG on distribution planning is not to idle capacity but rather to defer future investments until load growth compensates for the penetration of DG. For a more rigorous explanation of this math, see the Electricity Journal article on Standby Rate design submitted in response to NSTAR-NEDGC-1-4.
3 Values shown are in 1992 dollars. Final determination of benefits should identify the appropriate inflation index to convert these values and subsequent calculations into current dollars.
4 It appears from DPU-92-92 that the costs shown for low-tension customers are inclusive of upstream costs for high-tension customers, but the report could also be interpreted to imply that these values are additive. Estimates shown here have been conservatively made on a non-additive basis but this should be verified by the DTE.

Grid component	NSTAR Marginal Cost, 1992 $/kW
Generation	$433.20
Transmission	$254
Distribution (high tension service)	$300 – $302
Distribution (low-tension service)	$494 - $556
Total marginal grid costs for high-tension customers	**$987 - $989**
Total marginal grid costs for low-tension customers	**$1,181 - $1,243**

This report was prepared by NSTAR to calculate the marginal cost of a kW of additional peak load, and is thus a precise surrogate for the savings that would be realized by NSTAR through a marginal reduction in a kW of peak load.

In the current restructured market, the benefits associated with avoided transmission and generation expense would not accrue to the regulated utility, and are therefore not appropriate for the calculation of grid benefits accruing to NSTAR. (They are however, real benefits created by DG and a failure to put a financial value on these benefits will necessarily assure a misallocation of capital in the overall electric system. Nonetheless, we do recognize that an allocation of this benefit would be rather complex in the context of this rate case given the limited jurisdiction of the DTE.) However, this still leaves a value of $300 – $302 which accrues to NSTAR when a high-tension customer installs a DG plant generating 1 kW at system peak and a value of $494 – $556 which accrues to NSTAR when a low-tension customers installs DG plant generating 1 kW at system peak. Additionally, NSTAR's calculations in DPU-92-92 indicate annual marginal O&M expenses of $23.73 - $23.81 per kW which would also presumably generate annual realizable savings to NSTAR from a kW of peak load reduction.

Referring back to equation 1, we can now calculate that a baseloaded, 100 kW DG system with a 95% reliability factor and a 10% system reserve margin that is installed on the premises of a low-tension customer will lead to *at least*:

Eq. 2 104.5 kW of peak capacity reduction x $494/kW = $51,623

of avoided system capacity investments for NSTAR, and:

Eq. 3 104.5 kW of peak capacity reduction x $23.73 = $2,479.79

of avoided annual system O&M cost savings for NSTAR.

The capital cost savings identified in equation 2 can then be amortized into a standby rate by using NSTAR's weighted average cost of capital to determine the annual debt-service costs which would be saved by NSTAR. If we use NSTAR's 15.07% required rate of return for cash working capital as provided in DPU-92-92 over a 25-year repayment schedule,[5] this system benefit could be factored into a standby rate via an annual credit of $8,055.14 to the DG installer, or $80.55/kW of installed capacity per year in this 100 kW example. This value could then be added to the O&M cost savings to yield an annual benefit of:

Eq. 4 $80.55/kW/year capital savings + $23.73/kW/year O&M savings = $104.28/kW/year

of benefit from distribution cost deferral resulting from DG installation.

As a final note, it is critical to realize that there is a fundamental disconnect between these calculations and NSTAR's proposed standby tariff. In the NSTAR tariff, our same 100 kW customer installed on low-tension service (e.g., a customer on a G-2 rate) would pay NSTAR $196.40 per installed kW over the course of the year to compensate NSTAR for the displaced upstream system assets. Based on the prior calculations of marginal capital and operating cost savings, an assumption that this investment would be effectively "idled" by the DG installation

5 DPU-92-92 does not indicate the term over which this return is based, so I have made a conservative assumption of 25 years. A more rapid repayment schedule would obviously increase the implied value of the benefit calculated and should be verified by the DTE.

necessarily implies that the return realized on NSTAR's grid investment through their proposed standby tariff would be that of a $51,623 one-time cost, recouped through a $19,640/kW payment over the life of the DG unit,[6] in addition to the annual O&M cost reduction of $23.81/kW. Even if one only assumes a 15-year lifetime for the DG plant, this would imply a rate that provides NSTAR with a return-on-assets of 38%, well in excess of the 15% used in the calculation of implied benefits. Thus, even if one disagrees with the inclusion of system benefits described above, one must conclude that the imposition of the proposed standby rate would create windfall profits for NSTAR well in excess of any cost imposed by idled system capacity. Thus, the calculations shown above suggest either that NSTAR has a much higher cost of capital than they had in 1992 when they performed their Marginal Cost of Service Study– which would suggest that the above calculations of benefits are too low – or else that NSTAR is seeking a rate-of-return from their standby tariff well in excess of the return they are earning through other capital investments – which would imply a tariff that is creating a substantial cross-subsidy from DG owners to other rate payers.

Reduction of transmission and distribution system line losses

The physics of electricity flow through a wire necessarily imply that some of the power put into one end of the wire will be dissipated as heat through the length of the wire before being recovered as useful electricity on the other end. At a national level, the U.S. Department of Energy calculates that 9.5% of the total power generated in central power plants is lost to transmission and distribution line losses before reaching end users.[7] As with the previous case, the precise losses in any one region can vary substantially as they depend on both the current flowing through the wire and the resistance of the wire.

Nonetheless, the salient point about these losses is that consumption from generation at the end of the wire <u>does not</u> impose line losses on the system while consumption from generation at a central station <u>does</u> impose line losses on the system. Therefore, a 100 kW DG facility

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6 This is actually an extreme case, since it implies that the system capacity investment is made in the year before the DG unit is installed, with no intervening period during which revenue has been recovered and no subsequent utilization of this system capacity through downstream load growth. Obviously this is not likely to be the case for most systems installed on an existing grid, so the over-compensation of NSTAR under the proposed standby rate is likely to be much higher than is suggested by this simple calculation.
7 Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2002*.

"costs" an average utility 100 kW in lost revenue every hour, but also saves that same utility 109.5 kW in procured electricity every hour. Once system losses are known and electricity costs at either end of the wire are quantified, this financial benefit can be readily estimated for a given DG installation.

In truth, the actual impact of this benefit is rather more nuanced than would be suggested by the above. Grid losses increase with the square of the current, and thus system losses are considerably higher during peak periods and in those portions of the grid which are particularly constrained. This location dependency is seen in NSTAR's response to NEDGC-2-20, wherein the peak system losses show a strong dependency on location of the customer interconnection to the NSTAR grid.[8]

Grid Section	Peak Load (MW)	System losses at peak load (MW)	System losses at peak load (%)	Cumulative loss at grid section (%)
Transmission	3,530.9	63.3	1.79%	1.79%
High Tension	3,530.9	145.3	4.11%	5.91%
Primary Distribution	3,530.9	175.3	4.96%	10.87%
Secondary Distribution	3,530.9	268.2	7.60%	18.47%

Note that this data is not directly comparable to the DOE/EIA data, since the DOE/EIA data is based on average losses throughout the year while the NSTAR data is based on losses during the peak periods (which would be expected to be much higher, as they indeed are). However, the clear implication of this time- and location-dependency means that the actual line loss savings delivered by any given DG unit will be greater during times of peak system congestion and/or in areas with little reserve margin.

8 This table aggregates the data provided by NSTAR's Boston Edison, Commonwealth Electric and Cambridge Electric Service territories, as provided in response to NEDGC-2-20. Data provided for Boston Edison territory did not list the loss in MW, but was extrapolated from the peak system capacity and % loss shown. Note also that the peak load provided by NSTAR is constant for all grid sections, suggesting that the peak load is calculated at a single point upstream or downstream, such as would be required to exclude the system losses from each section. One would need to understand precisely where this peak load is defined in order to precisely calculate the reduction in line loss that results from a kW of load reduction at the customer end of the wire.

As a practical matter, it is probably easiest to use a simple average line loss when calculating this benefit rather than trying to over-specify the actual benefit created by a specific installation. While this averaging would necessarily lead to a slight over-compensation of some DG operators at the expense of other DG operators, this economic inefficiency is probably justified by the alternative cost of precise metering throughout the grid such as would be required to calculate the actual reduction in line losses created by any particular DG system. However, it is worth noting that the NSTAR Marginal Cost Study (DPU-92-92) appears to calculate the costs of a marginal kW of load based on the peak, rather than average line loss, since the "marginal demand losses" have a factor of 1.1963 – 1.222 (e.g., a 19 – 22% implied line loss) allocated to raw transmission and distribution costs for the purposes of calculating monthly demand costs for customers connected to secondary distribution networks. Since these values are on a par with the cumulative losses shown in the previous table, they would seem to suggest that NSTAR believes the peak (as opposed to average) line losses are the most appropriate values to use when estimating the cost of a marginal kW of load, no matter when that kW occurs. I lack sufficient familiarity with the detail of this report to understand how this calculation was done, but do point out that the marginal cost of an additional kW of load is identical to the marginal savings from a reduced kW of load. Thus, if it is appropriate to use a 22% line loss to calculate marginal costs, then it is also necessarily appropriate to use a 22% line loss to calculate marginal benefits.

Notwithstanding this confusion, if one uses the national average of 9.5% system line losses, and if electricity procured for the NSTAR electric grid had an average annual wholesale cost of $0.02/kWh, then a DG unit would save NSTAR

Eq. 5 0.095 x $0.02/kWh = $0.0019 per kWh of DG generation.[9]

Given the energy dependence of this variable, it is probably best credited to DG units on a kWh basis rather than bundled into a kW-based demand charge.

9 Note that this calculation is on a cost, rather than revenue basis. Since the net impact of a kWh of DG generation is to reduce utility expenses by 0.095 kWh once line losses are taken into account (1.094 kWh of reduced purchase less 1.0 kWh of reduced sales), there is a net financial gain which is appropriately calculated only on the cost of those kWh rather than including the higher revenue per kWh at the customer meter.

Export of Reactive Power

In their analysis of the causes of the August 14th blackout, the U.S.-Canada Power System Outage Task wrote that: "Reactive supply is an important ingredient in maintaining healthy power system voltages and facilitating power transfers. Inadequate reactive supply was a factor in most of the [major North American outages of the last 30 years]." The U.S. DOE and the North American Reliability Council made the further link between reactive power and DG in their September 29, 1998 report "Maintaining Reliability and a Competitive U.S. Electricity Industry: Final Report of the Task Force on Electric System Reliability" when they said that "distributed resources… can provide both local onsite generation and VAR support [to] enhance system reliability."

These benefits are not delivered by all DG systems, but can be designed into any DG facility that uses a synchronous electric generator. Under some – but not all – rate structures, there is an implicit benefit paid to such generators through $/kVAR charges in standard tariffs. Our firm has periodically been called upon to design synchronous generation systems in which the electric generators were oversized to export reactive power to the grid, and hence reduce the overall $/kVAR charge paid by our customers. (Note that this was done not at the request of the local utility or regulator, but rather by a customer seeking to reduce their electric bill, thus providing further evidence for the value of market-based incentives that place a precise value on the grid-benefit created by DG.)

Since this charge already exists in many rate structures, the ability of some DG systems to export reactive power is thus the easiest to factor into existing rates: simply add a $/kVAR line-item to all rate structures. This will provide prospective DG owners with a clear financial incentive to design this capacity into their systems, and thus enable the grid to benefit from their actions.

Reduction in Energy Prices

DG systems which generate electricity at a higher efficiency than the delivered kWh that they displace (inclusive of grid losses) necessarily lead to a lower cost of energy for their owners and a lower demand for generation fuels. This point is made by NSTAR in their 1992 "Marginal Cost of Service Study" which states "..fuel savings associated with the installation of new non-peaking capacity because of inefficiencies may make the overall cost per kilowatt less than that of a peaker." In the broadest sense, much of the nation's DG installations can be reasonably described as "non-peaking capacity", and thus represent the lowest cost source of marginal grid capacity, as noted by NSTAR in 1992.

The difficulty for planning purposes is that the associated energy savings which derive from utility-owned non-peaking capacity accrue to the utility, and can therefore be factored into long-term grid planning purposes while the energy savings associated with non-utility owned DG accrue to the DG owner and thus are perceived as a net cost to the utility. However, this accounting challenge does not change the underlying truth of the assertion that efficient generation at the customer end of the wire represents the least-cost approach to provide marginal electric load, inclusive of all market participants. Indeed, one of the larger challenges facing a deregulated market is how to ensure the provision of low-cost, reliable electricity when the regulators cannot be reasonably expected to directly impact many of the unregulated market participants who have the ability to impact these desired goals.

However, there is a second savings from the reduction in energy prices that is somewhat more difficult to quantify, but no less real. By reducing the demand for power generation fuels, the laws of supply and demand would imply that the price of those upstream fuels also falls. A recent analysis by Energy and Environmental Analysis[10] (EEA), a Washington DC-based consulting firm examined this issue in some detail with a specific focus on the impact of high efficiency combined heat and power deployment on retail gas demand in Northeast, California and Texas markets. The analysis found that increased deployment of CHP in the Northeast could reduce regional gas consumption by 4.2% via a reduction in less efficient uses in the regions gas-fired (but less efficient) power-only, gas-fired central stations. A second analysis done jointly by EEA and the American Council for an Energy Efficient Economy (ACEEE)[11] examined the economic characteristics of the natural gas market and concluded that the relatively high inelasticity of the demand curve for natural gas implies that very small reductions in total demand can lead to large reductions in market clearing prices. The EEA/ACEEE report found that a 7.5% reduction in natural gas consumption would lead to a gas price reduction of 20%.

Thus, the penetration of more efficient generation – be it DG or central station – necessarily leads to a reduction in the demand for generation fuels, and therefore to a reduction in the prices for those fuels. This price reduction benefits all users of those fuels, and thus leads to broader societal (and utility) economic savings which are difficult to precisely quantify for any individual generator, but certainly real for an aggregated population of efficient DG power plants.

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10 "Natural Gas Impacts of Increased CHP", Energy and Environmental Analysis, October 2003. Available on the web at http://uschpa.admgt.com/CHP_GasOct03.pdf
11 Elliott, N. "Impacts of Renewable Energy and Energy Efficiency on Natural Gas Prices", ACEEE, September 2003.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Information Request DTE-NEDGC 1-8

In reference to the pre-filed testimony of Sean Casten at 4, lines 15-17, please list and describe all the projects undertaken by Turbosteam Corporation in Massachusetts where "the coupling of a steam turbine to a mechanical drive that displaces an electric motor load" was supported through DSM funds. Indicate the total cost of each project and the amount of DSM funds provided.

Response

Our firm has never received DSM funds for steam turbines coupled to mechanical drives in Massachusetts. The comment was based on two specific observations about such funds in other utility territories:

1) In 2001, we sold a 50 kW backpressure turbine generator to a customer in Japan through a Japanese firm. We subsequently partnered with this firm to sell more of these products, but the firm found that the local utilities were hostile to the installation of subsequent units that would reduce their revenue and raised numerous issues with respect to interconnection and standby charges which made it problematic for Turbosteam's partner to develop subsequent projects. Since that 2001 installation, Turbosteam has provided 4 "bare" turbines to this company without an electric generator, which our partner subsequently coupled to an existing motor load via a clutch. These systems are designed to provide power to existing mechanical drive loads when steam is available, and otherwise to "clutch off" and serve the power needs with the existing electric motor. Economically, this system has an identical impact on grid resources as a turbine-generator coupled to an electric generator, but has been much easier to install in Japan as it allows our partners to install these units without first getting the approval of local utilities. Turbosteam engineers have begun to investigate the use of this technology in the U.S. and concluded that this same design would in all likelihood be eligible for DSM funds, although we have not yet had the opportunity to pursue a project with this approach.

2) In New York City, Murray and York have produced a skid-mounted steam-driven centrifugal chiller which takes steam from the municipal distribution network and extracts mechanical power from the steam by reducing its pressure across the turbine, which is subsequently used to drive a centrifugal chiller. It is our understanding that these projects are supported by New York DSM funds, and have also been eligible for capacity reduction payments through New York's ICAP program.[12] Turbosteam was recently approached by Trane to develop a similar package but with an electric generator coupled to the turbine which could subsequently provide power to an electrically-driven Trane centrifugal chiller, but our companies elected not to pursue this strategy after concluding that such an architecture would not be eligible for DSM fund support since it included an electric generator, *even though the net impact on utility assets would be identical*.

12 Turbosteam has not provided any such units, so we do not have access to more specific information as requested by the DTE.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Information Request DTE-NEDGC 1-9

In reference to the pre-filed testimony of Sean Casten at 6-7, please provide any study to support the claim that: "... our generators are 3 times as efficient as the central power grid ..."

Response

Please refer to Mr. Casten's response to NSTAR-NEDGC-1-14 for a detailed answer to this question, and specifically to the article accompanying NSTAR-NEDGC-1-4, "Approaching Free Electricity…"

According to the US DOE/EIA Annual Energy Outlook 2002, the average central generating station in the United States has an efficiency of 33%. The responses to NSTAR-NEDGC 1-4 and 1-14 show that Turbosteam's installations achieve a minimum fuel-to-electric efficiency of approximately 80%. Furthermore, all of Turbosteam's systems are integrated into existing steam networks such that exhaust steam is used to serve process heating loads rather than being rejected to the atmosphere (and hence wasted) as it is in a power-only central power plant. On an overall basis, it is thus not uncommon for our integrated plants to have efficiencies of 80 – 90% (total useful energy recovered / total fuel input), which would thus be (80/33 – 90/33) = 2.4 – 2.7 times as efficient as the central power grid.

However, the more accurate analysis must take into account the marginal efficiencies and marginal grid impacts since this describes the actual environmental and economic impact from reduced fuel consumption post-generator installation. The marginal efficiency of Turbosteam's generators is thermodynamically complex to calculate, but is shown to be considerably higher than 80% in the data shown for Middlebury College in response to NSTAR-NEDGC-1-14, by virtue of the fact that the act of operating a backpressure turbine-generator tends to reduce thermal losses elsewhere in a steam plant. (The Middlebury data shows a marginal efficiency of 151%, which does not reflect a violation of thermodynamic principles, but rather a reduction in thermal waste – and hence fuel input – post-installation. The detailed thermodynamic basis for this assertion is provided in the article referenced above in response to NSTAR-NEDGC-1-4.) On the other side of the equation, the marginal efficiency of the grid is widely understood to be less than the average 33% efficient generator by virtue of the presence of less-efficient, but low-cost and easily dispatchable peakers. The actual efficiency of a marginal unit of generation is difficult to quantify, but can be qualitatively seen to be less than the average if one recognizes that 100 kW of load reduction is unlikely to impact baseloaded coal or nuclear plants before it impacts gas- and oil-fired gas turbines and I.C. engines which are more readily started and stopped.[13]

Thus, if one assumes that the marginal efficiency of a Turbosteam generator is likely to be closer to that observed at Middlebury College, and further that the efficiency of a displaced unit of marginal generation is likely to be less than 33% (say, 25%), then a Turbosteam generator would be 151/25 = 6 times as efficient as the central power grid.

Given the uncertainty and complicating factors of these marginal calculations, and given the fact that an average calculation is too conservative, I used a factor of 3X as efficient to pick the conservative end of this 2.4 – 6x range.

13 The reduced efficiency of marginal generation is also seen in the US EPA's two calculations of carbon dioxide emissions associated with power generation, since CO_2 emissions are a direct function of fuel usage per kWh. In their 1999 report "Carbon Dioxide Emissions from the Generation of Electric Power in the United States" (available on the web at http://www.epa.gov/globalwarming/publications/emissions/co2emiss00.pdf), they calculate that an average kWh of electricity generation in Massachusetts is accompanied by the release of 1,077 lbs of CO_2. By contrast, another 1999 EPA report "Emissions Factors, Global Warming Potentials, Unit Conversions, Emissions and Related Facts" (available on the web at http://www.epa.gov/appdstar/pdf/brochure.pdf) calculates that a marginal kWh of electricity generation in Massachusetts is accompanied by the release of 1,726 lbs of CO_2. The 60% increase in CO_2-intensity per kWh necessarily implies a comparable reduction in fuel efficiency between average and marginal power plants, although calculating the precise reduction in efficiency is not possible from these values without also knowing the relative fuel mix for the two generator populations.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Information Request DTE-NEDGC 1-10

In reference to the pre-filed testimony of Sean Casten at 9, lines 13-14, please provide any study to support the statement that: AWe found that the NSTAR rate has the least negative impact on DG systems that are base-loaded and to systems that peak during the winter months.@

Response

Please see the responses to NSTAR-NEDGC-1-12 and NSTAR-NEDGC-1-15.